Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

August 26, 2010

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Vice President ·
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2010 AUG 26 P 3:49
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street, First Floor
Kekuanaoa Building
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 03-0417
East Oahu Transmission Project ("EOTP")
EOTP Phase 1 Cost Report

Pursuant to Decision and Order No. 23747 ("D&O 23747"), issued October 19, 2007, in Docket No. 03-0417, East Oahu Transmission Project ("EOTP"), Hawaiian Electric Company, Inc. ("Hawaiian Electric" or the "Company") hereby provides (1) an interim report accounting for the expenditures to-date for EOTP Phase 1, and (2) an updated estimate of the total costs for EOTP Phase 1, including remaining charges.[1]

The total estimated cost of EOTP Phase 1 is approximately $58,061,000, which includes Hawaiian Electric's actual costs of $56,292,000 through June 30, 2010, and an estimate of $1,769,000 for the outstanding costs to complete EOTP Phase 1. The $58,061,000 cost estimate for EOTP Phase 1 is approximately $851,000 or 1.5% higher than the cost estimate of $57,210,000 identified by Hawaiian Electric in its direct testimony HECO T-19A, filed July 30, 2010, in Docket No. 2010-0080 (HECO 2011 Test Year Rate Case). Additional time is required to accurately account for the outstanding charges. Hawaiian Electric will submit the final EOTP Phase 1 cost report to the Commission after all of the outstanding charges have been reconciled.

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[1] D&O 23747 requires Hawaiian Electric to "submit a report within sixty days of the Proposed Project's commercial operation, with an explanation of any deviation of ten percent or more in the Proposed Project's cost from that estimated in the Application." As explained in its application and testimonies in Docket No. 03-0417, the EOTP project was to be completed in two phases, i.e., Phases 1 and 2. EOTP Phase 1 was completed on June 29, 2010; therefore, the EOTP Phase 1 cost report is due no later than August 28, 2010.

By letter dated March 29, 2010 in the subject proceeding, Hawaiian Electric requested Commission approval to modify the project scope and cost for EOTP Phase 2. On March 31, 2010, the Commission "direct[ed] HECO to file any request for approval to modify the project scope and costs for Phase 2 of the EOTP by application in a separate proceeding." The application for approval to modify EOTP Phase 2 was therefore submitted in a separate docket (i.e., Docket No. 2010-0062) pursuant to the Commission's direction. Assuming Commission approval is received to modify the project scope and cost for EOTP Phase 2, the cost reporting for EOTP Phase 2 will be submitted in Docket No. 2010-0062.

EOTP Phase 1 Project Description

EOTP Phase 1, which was completed and placed into service on June 29, 2010, involved the installation of 0.5 miles of new underground ductline for 46kV subtransmission lines, and related work at eight substations (i.e., Kamoku, McCully, Makaloa, Kewalo, Kuhio, Waikiki, Ena, and Kapahulu Substations), to interconnect three 46kV circuits out of the Pukele Substation, at the end of Hawaiian Electric's Northern 138kV transmission corridor, to four 46kV lines connected to Hawaiian Electric's Southern 138kV transmission corridor. See Exhibit A for a more detailed description of the EOTP Phase 1 project, as well as the benefits from the implementation of the project.

EOTP Phase 1 Cost Estimate

In its application, filed December 18, 2003, in Docket No. 03-0417, Hawaiian Electric provided cost estimates of $41,587,000 for Phase 1 and $13,837,000 for Phase 2, for a total cost of $55,424,000 for the EOTP. In its supplemental direct testimony HECO ST-9, filed July 22, 2004, Hawaiian Electric revised its costs estimates for EOTP Phases 1 and 2 to $41,893,000 and $13,751,000, respectively, for a total cost of $55,644,000. (In its rebuttal testimony HECO RT-9, filed August 30, 2005, Hawaiian Electric did not revise the cost estimates for EOTP Phases 1 and 2.) The revised cost estimate was prepared in 2004 and was based on placing EOTP Phase 1 into service in 2007. The revised estimate of $55,644,000 for EOTP was included in D&O 23747.

Hawaiian Electric's most recent cost estimate for EOTP Phase 1 was provided on July 30, 2010 as part of the direct testimony HECO T-19A in Docket No. 2010-0080 (Hawaiian Electric 2011 Test Year Rate Case). The updated total cost estimate for EOTP Phase 1 cited in the direct testimony was $57,210,000, based on a June 29, 2010 service date with actual costs through May 31, 2010 plus estimated outstanding costs.

The current cost estimate for EOTP Phase 1 is $58,061,000 with actual costs through June 30, 2010 plus estimated outstanding costs. The current cost estimate is approximately $851,000 or 1.5% higher than the $57,210,000 estimate cited in direct testimony HECO T-19A. The increase is due to a more accurate accounting of outstanding charges. When the cost estimate was being developed for direct testimony HECO T-19A, there were numerous EOTP Phase 1 construction activities occurring simultaneously. For example, final 46kV overhead connections, substation construction, and substation testing were occurring in June 2010.

This cost report provides an explanation of the cost increase between the $41,893,000 cost estimate prepared in 2004 and the current cost estimate for EOTP Phase 1 of $58,061,000, which is approximately $16,168,000 or 39% higher. Exhibit B shows the 2004 cost estimate for EOTP Phase 1, and the total estimated cost for EOTP Phase 1 with actual costs through June 30, 2010 plus estimated outstanding costs.

A table showing the revised and current costs for EOTP Phase 1 by the major components, and the cost variance, is provided below:

Project Component	2004 Estimate	Current	Variance
Planning Costs	$26,396,000	$33,206,000	$6,810,000
Permitting and Approval Costs	$1,491,000	$2,768,000	$1,277,000
Subtransmission Line Costs	$3,399,000	$5,480,000	$2,081,000
Transmission Substation Costs	$8,603,000	$13,241,000	$4,638,000
Distribution Substation Costs	$2,004,000	$3,367,000	$1,363,000
Total Costs:	$41,893,000	$58,061,000	$16,168,000

Reasons for the Cost Increases

As shown in Exhibit B, the estimated cost of $58,061,000 at completion for EOTP Phase 1 is approximately $16,168,000 higher than the $41,893,000 estimate prepared in 2004 and reflected in D&O 23747. The current cost estimate reflects higher costs due to the higher than estimated construction and materials costs, and the delay in the start of construction for Phase 1. These three cost drivers account for approximately $14,308,000 (88%) of the $16,168,000 total increase. The costs and the primary causes of the cost variances for each component of EOTP Phase 1 are discussed in more detail in Exhibit C.

Project Schedule Delays

As stated in supplemental direct testimony, HECO ST-6, page 4, in Docket No. 03-0417, which was submitted on July 22, 2004, the estimated completion dates for EOTP Phase 1 and Phase 2 were mid-2007 and early 2009, respectively. The completion date for EOTP Phase 1 assumed that construction would start in mid-2006, and would take 12 months. EOTP Phase 1 was placed in service on June 29, 2010, approximately three years later than initially estimated in Docket No. 03-0417.

The main reason for the delay was that the Company was not able to start construction until June 2008. The delay in the start of construction was due to the longer than anticipated proceeding for Docket No. 03-0417, and the resulting need to reschedule the manufacturing and delivery of the long-lead materials, and the availability of Company engineering personnel and consultants. The delay in the start of construction delayed the completion date for EOTP Phase 1 from 2007 to 2010.

Based on the Schedule of Proceedings approved by the Commission in Order No. 20968, the total proceeding was estimated to take approximately 22 months and be completed by the third or fourth quarter of 2005. The schedule was also dependent on the Commission's review, as the accepting agency, of the Environmental Assessment ("EA") for the EOTP, and a Commission determination that an Environmental Impact Statement ("EIS") was not required. The notice of the Final EA and the Commission's April 8, 2005 Finding of No Significant Impact were published in the April 23, 2005 edition of the Office of Environmental Quality Control's "The Environmental Notice." No appeal was filed during the 30-day public review period, which ended on May 23, 2005. Thus, the Environmental Review ("ER") process was deemed complete on May 23, 2005.

With the completion of the ER process on May 23, 2005, Hawaiian Electric and the other parties in the docket submitted a proposed procedural schedule, which was approved by the Commission in Order No. 21930 on July 20, 2005. Pursuant to Order No. 21930, an evidentiary hearing was scheduled for early November 2005.

The evidentiary hearing concluded on November 8, 2005, and based on the availability of transcripts by December 8, 2005, the Opening and Reply Briefs were originally scheduled to be filed on December 30, 2005 and January 20, 2006, respectively. However, due to the holiday season and unexpected emergencies with one of the parties, the deadlines for the briefs were extended such that the Opening Briefs were filed on February 13, 2006, and Reply Briefs were filed on March 6, 2006 – a delay of approximately six weeks.

Due to the delays that had been incurred, the mid-2007 completion date for EOTP Phase 1 was no longer achievable, even if the Commission's approval of the project had come shortly thereafter. As mentioned above, the mid-2007 service date was based on the regulatory proceeding being completed by the third or fourth quarter of 2005. The main drivers for the service date were the procurements for the long-lead materials required for Kamoku Substation – 138kV Gas Insulated Substation ("GIS") switchgear, 138-46kV, 80MVA transformer, and 46kV GIS switchgear. Accordingly, in order to meet the mid-2007 service date, orders would have needed to be placed for the long-lead materials by the first quarter of 2006. This would have ensured arrival of the equipment in Hawaii by late 2006 to early 2007, which would have allowed sufficient time for installation and testing to be completed by mid-2007.

The Commission issued a Proposed Decision and Order No. 23610 on August 24, 2007, and a final decision pursuant to D&O 23747 on October 19, 2007. (Only two Commissioners were present at the November 2005 evidentiary hearing [i.e., Chairman Caliboso and Commissioner Kawelo]. Commissioner Kawelo subsequently retired from the Commission, and was replaced by Commissioner Cole in July 2006. However, Commissioner Cole disqualified himself from the EOTP proceeding in order to avoid any questions regarding his impartiality arising from his former position as Executive Director of the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs. It was not until Commissioner Kondo was appointed in July 2007 that a quorum was available to issue a decision in the EOTP proceeding.)

The proceeding from start (i.e., Application filing date) to finish (i.e., issuance of D&O 23747) lasted approximately 46 months. The actual duration of the proceeding was approximately two years longer than the initial estimate of 22 months.

In addition to the longer than estimated time for the proceeding, due to the uncertainty of when during the 2006 through 2007 time period a final decision would be issued in the docket, the manufacturers gave up the manufacturing time slots at their respective factories for the equipment that was reserved for EOTP Phase 1. As a result, the manufacturers could no longer guarantee the same manufacturing and delivery lead times that were quoted back in 2005. After D&O 23747 was issued in October 2007, Hawaiian Electric held discussions with the manufacturers of the long-lead materials for the Kamoku Substation to determine when their respective equipment could be manufactured, delivered to Hawaii, and installed given a new release for manufacture date of early 2008. Based on those discussions, it was determined that the equipment could possibly arrive in Hawaii by the third or fourth quarter of 2009.

In addition to the long-lead time for materials, a reassessment of the availability of Company engineering personnel and consultants was needed. Similar to the long-lead materials manufacturers, because of the uncertainty of the timing of when a final decision would be issued, engineering personnel and consultants initially assigned to EOTP Phase 1 were assigned to other projects and assignments in the interim. These interim assignments impacted when these engineering resources could return to working on EOTP Phase 1 in earnest which, in turn, extended the engineering durations from the 2005 assumptions.

Based on discussions with the manufacturers and the rescheduling of engineering resources, a new schedule for EOTP Phase 1 was developed, which resulted in a new service date of mid-2010.

After D&O 23747 was issued in October 2007, the cost estimates for the materials and construction were reviewed and adjusted based on 2007 actual costs on other projects. Based on these adjustments and based on a June 2010 service date, the EOTP Phase 1 cost estimate was revised to approximately $57,112,000.

Cost Management

The Company did take steps to manage the project cost for EOTP Phase 1. At the corporate level, the Company's project authorization (i.e., management approval) process monitors overall costs on a capital project such as EOTP Phase 1. If a project's total cost is forecasted to exceed its total authorized cost by 20% and $100,000, then the project needs to be reauthorized by Company executives. After D&O 23747 was issued in October 2007, a revised schedule and budget were developed for EOTP Phase 1. In December 2007, the Company authorized EOTP Phase 1 for a mid-2010 service date at a budget of $57,112,000. From December 2007 to June 2010, the total cost for EOTP Phase 1 has never increased to the 20% and $100,000 re-authorization threshold.

In addition, as mentioned in HECO T-1, page 11, in Docket No. 03-0417, the Company formed an Executive Team in 2002 to provide senior executive oversight of EOTP and ensure that the project continued to move forward until closure. The Executive Team was chaired by Hawaiian Electric's Senior Vice President of Operations and consisted of various officers from different areas in the Company. Since 2002 until present (2010), the Executive Team meets regularly to receive project updates and provide guidance to the project team.

At the project level, every month, actual costs would be monitored and compared to the spending pattern that was authorized in December 2007. If there appeared to be high (or low) expenditures in a given time period as compared to the authorized amounts for the same period, then appropriate action would be taken to determine the cause of the high (or low) expenditures.

Periodically, the supervisors of the Company resources assigned to the project would be notified of major activities that were behind schedule and major activities that were forthcoming. This was to assist the supervisors in ensuring that their resources can give the appropriate attention at certain critical points in the project. Periodic meetings were held with the project team to review the project status and to address issues including expenditures. In addition, smaller topic-specific meetings would be conducted as needed to address issues. Finally, before significant changes in scope occurred on the project, the changes had to be clearly described and estimated. After the impacts of the changes were identified, then the proposed scope changes would be routed for review and approval to the appropriate management levels in the Company before they could be implemented as part of the project.

The procurement of materials and outside services for EOTP Phase 1 was guided by *The Energy Delivery Contract Guidelines* ("Contract Guidelines") dated, August 18, 2003. While the Contract Guidelines encourage bidding to procure materials or services, it also provides guidance on when it is appropriate to pursue non-bid contracts. A copy of the Contract Guidelines is provided as Exhibit D.

The major materials that were competitively procured for EOTP Phase 1 were primarily related to the Kamoku Substation. The materials included the 80MVA transformer, 46kV GIS switchgear, and relay panels. The control and relay wiring, electrical cabinets and batteries were also competitively procured, but as part of the electrical construction services procurement process and not directly as a material purchase.

The following major materials were not competitively procured on EOTP Phase 1. For the Kamoku Substation, the 138kV GIS was procured on a sole-source basis as described in Exhibit C. In addition, the Remote Terminal Unit ("RTU") and Human-Machine Interface ("HMI") were procured on a sole-source basis with manufacturers that have reliably provided equipment in the past that can communicate with the Company's Energy Management System.

For the subtransmission lines, nearly all the materials such as 46kV cables, 12kV cables, terminators, and splices are stock items that were provided directly from the Company's inventory.

For the distribution substations, the 12.5MVA transformer and 15kV switchgear for Makaloa Substation were procured through established alliances that the Company has with certain manufacturers for these types of equipment. The motor operators for the 46kV switches were procured on a sole-source basis with a manufacturer that has reliably provided a product that meets the Company's operating and safety requirements. The remaining materials such as

46kV switches, interrupters, 46kV bus conductors, and control and relay wiring are all stock items that were provided directly from the Company's inventory.

The following outside services work for EOTP Phase 1 were procured through a competitive bidding process: the construction of the subtransmission ductlines and manholes, the infrastructure work at Kamoku Substation, and the relay and control wiring at Kamoku Substation.

The following major outside services for EOTP Phase 1 were procured on a qualifications-based selection process: the Environmental Assessment ("EA") preparation as part of the Environmental Review process in the Docket No. 03-0417 proceeding and the engineering design for Kamoku Substation. For the EA preparation, a cross-functional selection committee was established. Four reputable Honolulu-based environmental consulting firms were invited to present their qualifications to the selection committee. After considering each firm's qualifications, the committee selected a consultant for which a non-bid contract would be negotiated. To ensure that the successful consultant's price was reasonable, effort and costs on other EAs or environmental impact statements done previously for the Company were reviewed.

Similarly, a cross-functional selection committee was established for the engineering design for Kamoku Substation. Four mainland consulting firms that have successfully done work for the Company on past projects were invited to present their qualifications to the selection committee. One of the invited firms declined to present their qualifications. After considering each firm's qualifications, the committee selected a consultant for which a non-bid contract would be negotiated. To ensure that the successful consultant's price was reasonable, effort and costs on other projects done previously for the Company were reviewed.

The following major outside services were not competitively procured on EOTP Phase 1: the outside legal counsel and engineering studies to support the Docket No. 03-0417 proceeding, construction management for the construction of the subtransmission line ductlines and manholes, and the construction management for the Kamoku Substation construction. These types of services are needed to address issues and problems, which are difficult to identify upfront and quantify for a competitive procurement process. Given the history and complexity of the project and the urgency to implement EOTP Phase 1 (Koolau/Pukele Overload Situation), the Company procured these services on a sole-source basis with firms that have a proven performance record and extensive history with the Company.

As shown in Exhibit B, $20,370,000 of the total $23,117,000 AFUDC estimated for EOTP Phase 1 is associated with the Pre-2003 Planning and Permitting Costs. Therefore, meeting the revised service date of June 2010 for EOTP Phase 1 was a priority to contain the AFUDC costs. Any delay beyond June 2010 would continue to increase AFUDC, with the most impact coming from the Pre-2003 Planning and Permitting Costs. Therefore, the critical path activities, in other words, the activities that drive the service date of the project, were monitored closely and given priority if resources were in conflict with other activities. The critical path activities for EOTP Phase 1 were the procurement, installation, and testing of the 138kV GIS, 80MVA transformer, and 46kV GIS for Kamoku Substation.

To further minimize AFUDC on the project, the other EOTP Phase 1 activities that were not on the critical path were scheduled to occur as late as possible without jeopardizing the overall service date. Some of these non-critical path activities on EOTP Phase 1 included the design and construction of the various subtransmission lines and distribution substations. By allowing these non-critical path activities to occur as late as possible, the costs associated with these activities would in turn be booked later to the project. Correspondingly, the timeframe (the month costs are booked to the service date) that AFUDC is applied to these booked costs would be shorter in duration, which in turn lessens the overall AFUDC costs.

Overview of Cost Estimating Process

The process utilized to develop cost estimates for EOTP included these basic steps: 1) identify the scope of work, 2) identify deliverables, 3) identify risks, and 4) create a schedule and cost estimate.

As stated in HECO T-9 in Docket No. 03-0417, the Company used various sources to develop the cost estimates including estimates and actual costs from previous Company projects, and estimates from industry consultants and material suppliers.

To a certain degree, detailed engineering could have improved the cost estimates for the 12kV and 46kV cable installations, the transmission substation infrastructure work, and the equipment installations for the distribution substations. As explained in Exhibit C, there were numerous challenges that occurred during the installation of the 12kV and 46kV cables that significantly increased the Company construction labor hours. Detailed engineering would have likely identified some of these risks and appropriate adjustments could have been made to the cost estimate. For the transmission substation infrastructure work, detailed engineering did reveal that significantly more work was required than initially estimated. However, the detailed engineering occurred in 2005, after the initial estimates were developed for the proceeding in 2003. And finally, detailed engineering would have more clearly defined the scope of work for the distribution substations and the appropriate increases in Company construction labor could have been made in the estimates.

However, detailed engineering likely would not have improved the cost estimates for the other major cost items such as the construction of the ductlines and manholes for the subtransmission lines, and the materials for the transmission and distribution substations. The increased costs for those services and goods were influenced by the market demand, as supported by the Handy-Whitman Index of Public Utility Construction Costs, Bulletin No. 171 for the period 2003 through 2008.

If the Company had performed some detailed engineering prior to filing the Application, submission of the Application would have been delayed, which would have delayed the overall project schedule. As noted in Hawaiian Electric's Opening Brief in Docket No. 03-0417 (pages 34-35), there was an urgency to install EOTP Phase 1 to address the Koolau/Pukele Overload Situation. The timing of the Application was driven by the need to address the Koolau/Pukele Overload Situation as expeditiously as possible.

Sincerely,

Darcy L. Endo-Omoto
Vice President
Government & Community Affairs

Attachments

c: Division of Consumer Advocacy (3 copies with attachments)
Henry Q Curtis (3 copies with attachments)
Representative Scott Saiki (3 copies with attachments)
Karen Iwamoto, Palolo Community Council (1 copy with attachments)
Darlene Nakayama (Hoolaulima O Palolo) (1 copy with attachments)
Corey Park, Esq./Pamela Bunn, Esq. (Malama O Manoa) (1 copy with attachments)

EOTP Phase 1
Project Description and Benefits

Project Description

EOTP Phase 1, which was completed and placed into service on June 29, 2010, involved the installation of 0.5 miles of new underground ductline for 46kV subtransmission lines, and related work at eight substations (i.e., Kamoku, McCully, Makaloa, Kewalo, Kuhio, Waikiki, Ena, and Kapahulu Substations), to interconnect three 46kV circuits out of the Pukele Substation, at the end of Hawaiian Electric's Northern 138kV transmission corridor, to four 46kV lines connected to Hawaiian Electric's Southern 138kV transmission corridor. (See Exhibit A, page 3.) More specifically, EOTP Phase 1 involved: (1) installation of six underground 46kV lines in the Ala Moana, McCully, Moiliili, and Kapahulu areas, (2) installation of a 138kV/46kV transformer at the existing Kamoku Substation with associated protective relaying, (3) installation of a 46kV/12kV transformer at the existing Makaloa Substation with associated switchgear, (4) various switching and reconnections on the existing 46kV and 12kV systems near the Makaloa and McCully Substations, (5) removal of existing 46kV and 12kV cables between the Makaloa and McCully Substations, (6) removal of an existing 46kV/12kV transformer and associated switchgear from the McCully Substation, and (7) modifications of various existing distribution substations in the Honolulu area.

Project Benefits

With the implementation of EOTP Phase 1, the Koolau/Pukele Line Overload Situation has been fully addressed and the Pukele and Downtown Reliability Concerns have been partially addressed. (Koolau/Pukele Line Overload Situation: An overload situation wherein one of the three 138kV transmission lines that transport power to the Koolau/Pukele Service Area[1] in the Northern 138kV transmission corridor could overload whenever the other two transmission lines are out of service. Pukele Reliability Concern: Pukele Substation, located at the end of the Northern 138kV transmission corridor, would be without power if the two 138kV transmission lines serving the substation were to be lost. The Pukele Substation serves critical loads such as Waikiki, State Civil Defense, Hawaii Air and Army National Guard Headquarters, and the University of Hawaii. Downtown Reliability Concern: Archer, Kewalo and Kamoku Substations, all located in the Southern 138kV transmission corridor, would be without power if the two 138kV transmission lines serving Archer Substation were to be lost. Kewalo Substation receives power from Archer Substation via two 138kV transmission lines, and Kamoku Substation receives power via one 138kV transmission line from Kewalo Substation. These substations serve critical loads such as the Honolulu Police Department Headquarters and the Hawaii Convention Center.)

Prior to the completion of EOTP Phase 1, the loss of the two Koolau-Pukele 138kV transmission lines serving the Pukele Substation would have caused an interruption of electricity service to Pukele customers. Most of Hawaiian Electric's customers in the area serviced by the

[1] The Koolau/Pukele Service Area is the combined area served by the Koolau and Pukele Substations.

substation, which extends from Makiki to Waikiki, and from Koolau to Kaimuki, would have been out of power until one of the two 138kV transmission lines could be restored to service. (The remaining customers would experience a service interruption of up to six seconds, as their service is automatically transferred to Archer Substation.)

EOTP Phase 1 substantially increased the reliability to customers served by these circuits. As a result, the customers shifted from circuits served by Pukele Substation to circuits served by the Kamoku and Archer Substations (representing an estimated 80 MW) will not experience a loss of electric service if both the Koolau-Pukele 138kV transmission lines become unavailable (i.e., causing an outage of the Pukele Substation). In addition, if an outage of the Pukele Substation occurs, a segment of the customer load served by the Pukele Substation (estimated at approximately 63 MW) will automatically be transferred to the Archer, Kamoku and Koolau Substations. The automatic transfer scheme requires up to 6 seconds for mechanical switches to open and close, transferring the load from the primary circuits served from the Pukele Substation in the Northern Corridor to the back-up circuits served from the Kamoku and Archer Substations in the Southern Corridor. Therefore, customers included in this load block will experience up to a 6-second outage. Overall due to the installation of EOTP Phase 1, the customers in the Waikiki, Diamond Head, certain parts of Kaimuki, Palolo, Moiliili, McCully, and Makiki areas would experience either no outage or a momentary outage (i.e., approximately six seconds) if both the Koolau-Pukele 138kV transmission lines become unavailable.

With respect to the remaining customers served from the Pukele Substation after Phase 1 is installed (representing approximately 58 MW), during a prolonged outage of the Pukele Substation, Hawaiian Electric Troublemen would be sent out to perform manual switching in the field. The switching would transfer the remaining Pukele load to 46kV feeders at a different part of the Northern Corridor served by the Koolau Substation. The manual switching is expected to require approximately 2 to 4 hours to complete before service would be restored to the remaining customers. The affected areas include Manoa, Maunalani Heights, certain parts of Kaimuki, and Kahala. (The EOTP Phase 2 Modification will improve the outage time for these customers to one minute to several minutes.)

EOTP Phase 1

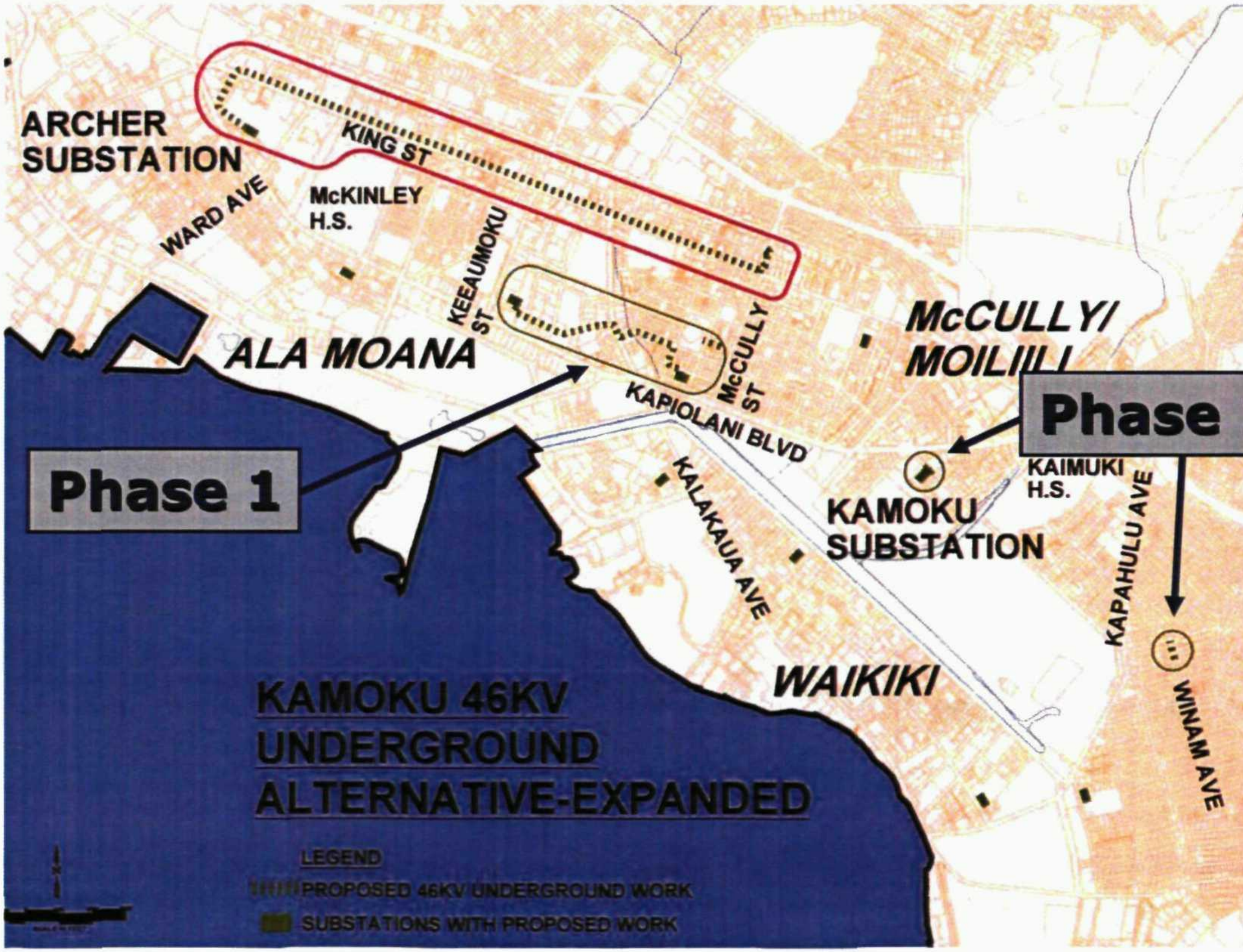

EXHIBIT A
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Project Title: East Oahu Transmission Project (EOTP) Phase 1
Budget Item: Y48500

COST SUMMARY

	Docket No. 03-0417 *Estimate*	(June 2010) Forecasted *Costs*	*Variance*
Planning	$12,836,000	$12,836,000	$0
Permitting & Approval	$1,172,000	$1,788,000	$616,000
HECO Labor (Non Construction)	$406,000	$533,000	$127,000
HECO Labor (Construction)	$707,000	$1,227,000	$520,000
Materials	$6,434,000	$9,171,000	$2,738,000
Outside Services (Consultant)	$979,000	$1,664,000	$685,000
Outside Services (Construction)	$2,059,000	$4,953,000	$2,894,000
Overheads	$2,340,000	$2,771,000	$432,000
AFUDC	$14,960,000	$23,117,000	$8,156,000
Total	$41,893,000	$58,061,000	$16,168,000
Service Date	June 2007	June 2010	

COST BY COMPONENT

	Docket No. 03-0417 Estimate	(June 2010) Forecasted Costs	Variance
Planning Costs			
Estimated	$12,836,000	$12,836,000	$0
AFUDC	$13,560,000	$20,370,000	$6,810,000
Total	$26,396,000	$33,206,000	$6,810,000
Permitting & Approval Costs			
Labor	$230,000	$268,000	$38,000
Materials	$0	$1,000	$1,000
Outside Services	$765,000	$1,237,000	$472,000
Overheads	$177,000	$282,000	$105,000
AFUDC	$319,000	$980,000	$661,000
Total	$1,491,000	$2,768,000	$1,277,000
Subtransmission Line Costs			
HECO Labor (Non Construction)	$180,000	$165,000	-$15,000
HECO Labor (Construction)	$194,000	$545,000	$351,000
Materials	$774,000	$953,000	$179,000
Outside Services (Consultant)	$0	$31,000	$31,000
Outside Services (Construction)	$1,462,000	$2,401,000	$940,000
Overheads	$598,000	$1,036,000	$438,000
AFUDC	$191,000	$348,000	$158,000
Total	$3,399,000	$5,480,000	$2,081,000
Transmission Substation Costs			
HECO Labor (Non Construction)	$108,000	$291,000	$183,000
HECO Labor (Construction)	$252,000	$232,000	-$20,000
Materials	$4,884,000	$6,876,000	$1,992,000
Outside Services (Consultant)	$979,000	$1,378,000	$399,000
Outside Services (Construction)	$449,000	$2,408,000	$1,959,000
Overheads	$1,159,000	$849,000	-$310,000
AFUDC	$774,000	$1,207,000	$433,000
Total	$8,603,000	$13,241,000	$4,638,000
Distribution Substation Costs			
HECO Labor (Non Construction)	$119,000	$77,000	-$41,000
HECO Labor (Construction)	$261,000	$450,000	$190,000
Materials	$776,000	$1,342,000	$566,000
Outside Services (Consultant)	$0	$255,000	$255,000
Outside Services (Construction)	$148,000	$144,000	$-4,000
Overheads	$582,000	$885,000	$303,000
AFUDC	$117,000	$212,000	$95,000
Total	$2,004,000	$3,367,000	$1,363,000

EOTP Phase 1
Cost Estimate Variance Explanation

Reasons for the Cost Increases

As shown in Exhibit B, the estimated $58,061,000 cost at completion for EOTP Phase 1 is approximately $16,168,000 higher than the $41,893,000 cost estimate prepared in 2004 and reflected in D&O 23747. The current cost estimate for EOTP Phase 1 is higher primarily due to the higher than estimated construction and materials costs, and the overall delay in the project. These three cost drivers account for approximately $14,308,000 (88%) of the $16,168,000 total increase. The costs and the primary causes of the cost variances for each component of EOTP Phase 1 are discussed below in more detail.

Cost Escalation

The EOTP Phase 1 cost increase is consistent with the mainland west coast electric utility cost trend for the 2003 to 2008 timeframe. Based on the *Handy-Whitman Index of Public Utility Construction Costs, Bulletin No. 171*, total distribution plant cost trend in the Pacific Region[1] increased approximately 50% from 2003 to 2008. Applying this 50% cost trend factor to the initial cost estimates for the subtransmission line, transmission substation, and distribution substations components for EOTP Phase 1, the total EOTP Phase 1 cost could have been expected to increase by $15,091,000 as shown below:

Project Component	Docket 03-0417	*50% Factor	Variance
Planning Costs	$26,396,000	$33,206,000	$6,810,000
Permitting and Approval Costs	$1,491,000	$2,768,000	$1,277,000
Subtransmission Line Costs	$3,399,000	*$5,099,000	$1,700,000
Transmission Substation Costs	$8,603,000	*$12,905,000	$4,302,000
Distribution Substation Costs	$2,004,000	*$3,006,000	$1,002,000
Total Costs:	$41,893,000	$56,984,000	$15,091,000

In addition, the EOTP Phase 1 cost increase is slightly more than the high-rise building costs trend in Honolulu for the 2003 to 2008 timeframe. Based on the *State of Hawaii Data Book 2008*, high-rise building cost increased approximately 39% from 2003 to 2008. Applying this 39% cost trend factor to the initial cost estimates for the subtransmission line, transmission substation, and distribution substations components for EOTP Phase 1, the total EOTP Phase 1 cost could have been expected to increase by $13,550,000 as shown below:

Project Component	Docket 03-0417	*39% Factor	Variance
Planning Costs	$26,396,000	$33,206,000	$6,810,000
Permitting and Approval Costs	$1,491,000	$2,768,000	$1,277,000
Subtransmission Line Costs	$3,399,000	*$4,725,000	$1,326,000
Transmission Substation Costs	$8,603,000	*$11,958,000	$3,355,000

[1] The Pacific Region includes Washington, Oregon, and California.

Distribution Substation Costs	$2,004,000	*$2,786,000	$782,000
Total Costs:	$41,893,000	$55,443,000	$13,550,000

Transmission (Kamoku) Substation Costs Component

The transmission substation is currently estimated at approximately $13,241,000, which is approximately $4,638,000 or 54% higher than the original cost estimate of $8,603,000. The $4,638,000 variance accounts for approximately 29% of the total EOTP Phase 1 variance of $16,168,000. The primary reasons for the increased costs for the transmission substation component are the higher than estimated costs for: (a) the materials, (b) the infrastructure work, and (c) the relay and control wiring electrical construction.

Materials. The transmission substation materials cost is currently estimated at approximately $6,876,000, which is approximately $1,992,000 higher than the original cost estimate of $4,884,000 and accounts for approximately 12% of the total EOTP Phase 1 variance of $16,168,000. The major contributors to the higher transmission substation materials costs include: (i) the 138kV Gas Insulated Substation ("GIS") switchgear, (ii) the 138kV-46kV, 80MVA transformer ("80MVA transformer"), and (iii) 46kV GIS switchgear.

138kV GIS switchgear. The major factors that contributed to the cost increase for the 138kV GIS switchgear include the actual price being higher than initially estimated, the delay in awarding the release for manufacture, and the Company's request to have the manufacturer install the equipment.

In 2003, the initial cost estimate for the 138kV GIS switchgear was $1,225,000. In 2005, after negotiating a sole-source non-bid contract with Mitsubishi Electric Power Products, Inc. ("MEPPI"), the resultant cost proposal for the 138kV GIS was $1,617,000, which was $392,000 higher than originally estimated. A sole-source non-bid contract with MEPPI was utilized because the existing 138kV GIS equipment at the Kamoku Substation was manufactured and installed by MEPPI through a competitive bidding process as part of the Kewalo-Kamoku 138kV Transmission Line project (Docket No. 7602), which went into service in 2002. To install the 80MVA transformer required for EOTP Phase 1, the existing 138kV GIS equipment needed to be expanded and connected to the proposed transformer. Due to the inherent complexity and specialization of GIS equipment, the manufacturer of the original equipment should be utilized to expand the equipment to accommodate additional line or transformer terminations. In addition, as noted by the Company's design consultant, Black & Veatch ("B&V"), it is unlikely another GIS supplier would be willing to provide expansion equipment for another supplier's equipment. Furthermore, if there was a GIS supplier willing to provide the equipment, there would likely be warranty and responsibility issues that would leave the Company at risk in the event there was an electrical fault after the equipment was put into operation. For the above reasons, the Company negotiated a sole-source non-bid contract with MEPPI for EOTP Phase 1.

As stated earlier, due to the inherent complexity and specialization of GIS equipment, the manufacturer of the original equipment should be utilized to expand the equipment to accommodate additional line or transformer terminations. Therefore, Hawaiian Electric had no practical options except to negotiate with MEPPI for EOTP Phase 1. For the original installation, which utilized a competitive bidding process, the Company could have specified and installed the full build-out of the 138kV GIS equipment as part of the Kewalo-Kamoku 138kV Transmission Line project. However, this would have significantly increased the cost of that project. Thus, there are trade-offs to consider with regard to how much to plan for and invest in an initial GIS installation versus expanding the equipment in the future and not being in the ideal situation to negotiate a competitive cost.

Another reason for the higher cost of the 138kV GIS switchgear was the delay in awarding the release for manufacture of the equipment. In 2005, when Hawaiian Electric first negotiated the procurement of the 138kV GIS with MEPPI, it was assumed that the service date for EOTP Phase 1 would be in 2007. However, the service date for EOTP Phase 1 was revised to mid-2010 after Commission approval to proceed with the project was received in October 2007. In 2008, and based on this revised schedule, MEPPI requested an increase in the cost to manufacture the 138kV GIS switchgear of $137,000, citing increases in the cost of steel and aluminum since the initial contract had been negotiated in 2005. Furthermore, MEPPI requested an additional $65,000 given that the equipment could not arrive at the project site until 2010 in order to avoid conflicts with arrival dates for other major equipment at the site based on the new revised EOTP Phase 1 schedule. The resultant cost for the 138kV GIS switchgear was an increase to $1,819,000.

Furthermore, the cost of the 138kV GIS switchgear was affected by Hawaiian Electric's request to have the manufacturer install the equipment. Initially, it was assumed that the Company's electrical crews would install the 138kV GIS switchgear. In 2008, during the Company's budgeting process for 2009 to 2013, it was determined that there might be a potential shortage of Company electrical crews to work at Kamoku Substation based on other forecasted Company projects at the time. Thus, it was decided that MEPPI should be requested to install the 138kV GIS switchgear to ensure that this work could be completed to meet the mid-2010 service date for EOTP Phase 1. Based on the Company's request, MEPPI requested competitive bids for the installation, which resulted in an installation cost of $590,000. This increase to the materials cost was slightly offset by a decrease of $50,000 in the Company's labor for construction forecast and a decrease in associated Company overheads of $394,000. However, not all of the decrease in the Company's labor is attributed to the 138kV GIS switchgear installation being transferred to MEPPI. (The relay and control wiring was also contracted out, which also contributed to the decrease in the Company labor for construction.)

As a result of the factors discussed above, the total forecasted cost for the 138kV GIS switchgear is $2,409,000, based on the initial contract with MEPPI ($1,617,000), the delay in the EOTP Phase 1 schedule ($202,000) and the request for MEPPI to install the equipment ($590,000). This is approximately $1,184,000 more than originally estimated for the 138kV GIS switchgear.

<u>80MVA transformer</u>. The major factor that contributed to the cost increase for the 80MVA transformer was the later date in awarding the release for manufacture. The initial estimate in 2003 for the transformer was $1,838,000. In 2005, three pre-qualified manufacturers were invited to bid on the transformer procurement. The bids ranged from $1,478,000 to $1,755,000. After a comprehensive evaluation, the manufacturer with the $1,478,000 bid,

Pauwels Canada, Inc. ("Pauwels"), was selected for contract negotiations. After negotiating with Pauwels, the resultant proposal increased the cost to $1,545,000. Thus, the transformer cost was approximately $293,000 less than originally estimated.

However, the procurement contract for the transformer with Pauwels in 2005 was negotiated assuming a 2007 service date for EOTP Phase 1. In early 2008, and based on the revised service date and schedule for EOTP Phase 1, Pauwels requested a $840,000 increase in the cost to manufacture the transformer, citing increases in the cost of raw materials, the costs from transformer component suppliers, and Pauwel's labor and overhead costs, as well as the strengthening of the Canadian dollar relative to the U.S. dollar. Thus, the cost of the transformer increased to $2,385,000, which is $547,000 more than originally estimated.

<u>46kV GIS switchgear</u>. The major factor that contributed to the cost increase for the 46kV GIS switchgear was the later date in awarding the release for manufacture. In 2003, the initial estimate for the 46kV GIS switchgear was $1,400,000. In 2005, three pre-qualified manufacturers were invited to bid on the 46kV GIS switchgear procurement. The bids ranged from $1,085,000 to $1,859,000. After a comprehensive evaluation, the manufacturer with the $1,085,000 bid, ABB, Inc. ("ABB"), was selected for contract negotiations. After negotiating with ABB, a resultant cost proposal increased the cost to $1,170,000. Thus, the 46kV GIS switchgear cost was approximately $230,000 less than originally estimated.

In 2005, similar to the other procurement contracts, the procurement contract for 46kV GIS switchgear with ABB was negotiated assuming a 2007 service date for EOTP Phase 1. In early 2008 and based on the revised service date and schedule for EOTP Phase 1, ABB requested a $278,000 increase in the cost to manufacture the 46kV GIS switchgear, citing increases in the cost of aluminum and steel and in labor costs in Germany, as well as the strengthening of the Euro relative to the U.S. dollar. Thus, the cost of the 46kV GIS switchgear increased to $1,448,000, which is $48,000 more than originally estimated.

In summary, the direct cost impact to the transmission substation major materials due to the service date being delayed from 2007 to 2010 was approximately $1,320,000, as follows: $202,000 for the 138kV GIS switchgear, $840,000 for the transformer, and $278,000 for the 46kV GIS switchgear. As stated earlier, the total materials cost variance for the transmission substation is approximately $1,992,000. Thus, the $1,320,000 materials cost increase related to the EOTP Phase 1 delay accounts for approximately 66% of the total materials cost variance for the transmission substation.

It should be noted that a decision was made by the Company to not re-issue bids for the materials, and instead, to negotiate with the successful bidders to get the materials to Hawaii as expeditiously as practical. This is because there was an urgency to install EOTP Phase 1 to address the Koolau/Pukele Overload Situation. (The urgency is summarized in Hawaiian Electric's Opening Brief in Docket No. 03-0417 [pages 34-35].) If the materials had been re-issued for bidding, the service date would have been delayed even further by another two to three months.

In addition to the direct procurement costs, there were other cost increases related to the materials for the transmission substation. For example, some of the outside consultant and Company labor (non-construction) costs increased due to materials related activities. Specifically, the total cost for outside consultants is currently estimated at approximately $1,378,000, which is approximately $399,000 higher than the original cost estimate of $979,000 for outside consultants. Also, the Company labor for non-construction is currently estimated at approximately $291,000, which is approximately $183,000 higher than the original cost estimate of $108,000.

More specifically, in 2004, B&V was retained as a consultant to develop material specifications, review manufacture drawings and develop designs for the infrastructure work and electrical installations related to Kamoku Substation. Through a qualifications based selection process, B&V was selected among three pre-qualified consultants to negotiate a contract. B&V's initial contract was $1,001,000, which was approximately $22,000 more than the initial 2003 estimate of $979,000 for an outside consultant. As the design work progressed, change orders (approximately $269,000 in total) were requested, which increased B&V's total forecasted costs to approximately $1,270,000, or $291,000 more than originally estimated. One of the significant items covered in the B&V change orders included the more involved review and coordination of the manufacturers' respective drawings for the 138kV GIS switchgear, 80MVA transformer, and 46kV GIS switchgear. The other significant items in the change orders included B&V's additional effort for the more involved infrastructure work and contracting out the electrical construction work, which will be discussed later in Exhibit C. The other remaining estimated costs (i.e., $108,000) for outside consultants cover various miscellaneous costs for printing, building permit, and other specialty consultants or contractors.

With regard to Company labor (non-construction) costs, current labor hours are forecasted at 6,881 hours compared with the initial estimate of 3,320 hours. The current average hourly labor rate for the Company personnel is approximately $42 per hour versus the initial estimated hourly rate of $33 per hour. The cost increase is due to primarily to more labor hours being required than originally estimated, and to a lesser degree, an increase in the average hourly rate for Company labor. The primary activities associated with this cost category are engineering review and coordination of B&V's design work and the procurement of materials. Other activities also include clerical services and project management. The significant factors that increased the Company labor for non-construction were the extended long-lead materials procurement process due to the extended docket proceeding and the more involved review and coordination of the manufacturers' respective drawings for the 138kV GIS switchgear, 80MVA transformer, and 46kV GIS switchgear. Similar to B&V, the other factors that increased the Company labor cost included more coordination for the more involved infrastructure work and contracting out the electrical construction work, which will be discussed later in Exhibit C.

The associated overheads for overall Company labor are estimated to be $849,000, which is approximately $310,000 less than the initially estimated amount of $1,159,000. Despite the increase in Company labor for non-construction, the overheads were offset by a decrease in Company labor for construction of approximately $20,000.

Infrastructure Work. The infrastructure work included the mechanical, civil, and lighting-type electrical construction[2] to accommodate the installation of the 138kV GIS switchgear, 80MVA transformer, and 46kV GIS switchgear. This type of work is normally contracted out and thus construction management is required to oversee the contractor. The current cost estimate for the outside construction work is $2,408,000, which is approximately $1,959,000 higher than the original cost estimate of $449,000. (This includes the infrastructure work as well as the relay and control wiring construction.)

In 2003, the infrastructure work was initially estimated at $449,000 and the associated construction management at $53,000.[3] These cost estimates were based on the assumption that only minimal work was required at Kamoku Substation to accommodate the new major equipment in EOTP Phase 1. It was assumed that the fire protection and heating, ventilation and air conditioning ("HVAC") systems installed as part of the Kewalo-Kamoku 138kV Transmission Line project that went into service in 2002, could be expanded with minimal modifications. The infrastructure work is currently estimated at approximately $1,453,000 and the associated construction management at $237,000.

Outside construction work. After detailed engineering commenced in 2005, it was determined that significantly more work was required for the transformer pad, fire protection, and HVAC controls. For example, the transformer pad design had to be increased to accommodate a larger 80MVA transformer than originally assumed.

In addition, with regard to fire protection, it had originally been assumed that the existing fire sprinkler system and fire alarm system for the existing 138kV to 25kV, 50MVA transformer would only need to be extended or expanded to cover the new 80MVA transformer. Instead, a separate stand-alone sprinkler system for the new 80MVA transformer was required. The existing fire alarm system also needed to be upgraded.

With regard to the HVAC controls, it had originally been assumed that the new HVAC controls could be powered from the existing electrical panels. However, the power requirements for the new HVAC controls required that new electric panels and additional wiring be installed.

As a result, when the entire infrastructure work was issued for competitive bidding in 2008 to three pre-qualified contractors, the bids ranged from $1,290,000 to $1,490,000. After a comprehensive evaluation, Ralph S. Inouye, the contractor with the $1,290,000 bid, was awarded the contract. While the infrastructure work is essentially complete, a change request is forthcoming (estimated at $163,000) that needs to be processed before the contract can be closed out. Thus, the infrastructure work is currently estimated at approximately $1,453,000, which is approximately $1,004,000 higher than the original estimate of $449,000.

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2 Lighting type electrical construction refers to electrical wiring and fixtures normally associated with a typical building such as lighting, outlets, and mechanical equipment.

3 When the initial estimate for construction management was developed in 2003, it was categorized under outside engineering because it was assumed that this service would be provided by the engineering consultant for the project at a cost of $53,000. Subsequently in 2006, TLH Project Management, LLC ("TLH") was retained to provide the construction management services. TLH is not an engineering company, and thus, their cost was categorized under outside construction, which added to the outside construction cost variance.

Construction management. As stated earlier, it was initially assumed that only minimal infrastructure modifications would be required at Kamoku Substation. However, after detailed engineering commenced in 2005, it was determined that significantly more work would be required for the transformer pad, fire protection, and HVAC controls. In 2006, TLH Project Management, LLC ("TLH") was retained to provide the construction management services. TLH's initial contract was based on the detailed engineering effort, which resulted in an initial contract of $187,000.

One of TLH's tasks under the initial contract was to support the Company's design consultant's efforts in obtaining the required building permit from the City and County of Honolulu's Department of Planning and Permitting for the infrastructure work. The building permit process (i.e., from application submittal to approval) was estimated to take approximately one year, which was the duration TLH assumed for the initial contract. In actuality, the building permit application process took 18 months, from December 2006 to June 2008. Thus, a change order of $50,000 was granted to cover TLH's efforts on the extended building permit application process.

As a result, the current estimated cost for TLH's construction management services for the infrastructure work is approximately $237,000 or $187,000 initial contract plus $50,000 for the building permit delay.

In addition, there were other cost increases related to the infrastructure work. As mentioned earlier, B&V and the Company labor costs increased due to more engineering and coordination required for the more involved infrastructure work. This additional effort contributed to B&V's current total forecasted cost of $1,270,000, and the Company's labor for non-construction cost of $291,000 for the transmission substation.

Relay and Control Wiring Construction. The relay and control wiring construction involves the installation of relay panels, junction boxes, conduits and wiring between the relay panels and various electrical equipment. When the initial estimate was developed in 2003, it was assumed that the relay and control wiring work would be performed by the Company's electrical crews in the 2006 to 2007 timeframe. Thus, the initial estimate was developed on this basis and no cost was allocated for outside contractors for this work.

However, based on the revised service date of mid-2010 for EOTP Phase 1, the relay and control wiring construction was planned to occur in the 2009 to 2010 timeframe. In 2008, similar to the 138kV GIS switchgear installation, it was determined that there might be a potential shortage of Company electrical crews to work at Kamoku Substation based on other forecasted Company projects at the time. Thus, it was decided that the relay and control wiring work should be contracted out to ensure that this work could be completed in time to meet the mid-2010 service date for EOTP Phase 1. Subsequently, when this work was issued for competitive bidding in 2009 to three pre-qualified contractors, the bids ranged from $668,000 to $724,000. After a comprehensive evaluation, Wasa Electrical Services, the contractor with the $668,000 bid, was awarded the contract. While the relay and control wiring construction is essentially complete, a change request is forthcoming (estimated at $100,000) that needs to be processed before the contract can be closed out. Thus, the relay and control wiring construction is currently estimated at approximately $778,000, which increased outside contractor costs by $778,000, because no contractor costs had been allocated for this work. However, the increase was slightly offset by a decrease of $20,000 in the Company's labor for construction forecast and a decrease in associated Company overheads of $310,000. As discussed earlier, not all of the decrease in the Company's labor is attributed to this relay and control wiring work being contracted out. The decrease is also attributed to the 138kV GIS switchgear installation also being contracted out (to the manufacturer).

In addition, other costs increased due to the relay and control wiring construction being contracted out. Costs for TLH, B&V, and Company labor increased due to the relay and control wiring construction being contracted out.

With the relay and control wiring construction being contracted out, construction management was needed to facilitate the procurement of a contractor and oversee the contractor's work. Thus, the Company requested TLH to provide the construction management services for this work, which increased TLH's contract by approximately $105,000. While the relay and control wiring construction is essentially complete, a change request (estimated at $43,000) is forthcoming that needs to be processed before the contract can be closed out. This is resulting in a total cost of $385,000 for the TLH contract: $237,000 for infrastructure related work and $148,000 for relay and control wiring.

With the relay and control wiring construction being contracted out, B&V was tasked to develop the specifications, so the work could be contracted out. Company labor was required to review the B&V specifications and coordinate the procurement of a contractor with TLH. This unanticipated additional effort contributed to B&V's current total forecasted cost of $1,270,000, and the Company's labor for non-construction cost of $291,000 for the transmission substation.

AFUDC. The AFUDC for the transmission substations component is currently estimated at approximately $1,207,000, which is approximately $433,000 higher than the original cost estimate of $774,000. The increase is due primarily to the increase in costs for the transmission substation overall, and to a lesser degree, the delay in service date from 2007 to 2010.

Subtransmission (46kV) Lines Costs Component

The subtransmission lines component is currently estimated to cost approximately $5,480,000, which is approximately $2,081,000 or 61% higher than the original cost estimate of $3,399,000. The $2,081,000 variance accounts for approximately 13% of the total EOTP Phase 1 variance of $16,168,000. The major reasons for the higher than estimated cost for the subtransmission lines are: (a) the higher costs for the ductlines and manholes for the new 46kV lines, (b) the 12kV and 46kV cable installations, and (c) the materials.

Ductlines and Manholes. Approximately 0.5 miles (i.e., 2,560 feet) of underground concrete-encased ductline (and associated manholes) was required for EOTP Phase 1. The required ductlines and manholes include: (1) 1,000 feet of ductline on Makaloa Street for the new Makaloa-McCully 46kV Lines; (2) 730 feet of ductline and two manholes on Pumehana

Street for the Pumehana 46kV Line; (3) 410 feet of ductline and two manholes on Date Street for the Kamoku 46kV Lines; and (4) 420 feet of ductline and two manholes on Winam Avenue for the Winam 46kV Line.

Ductline and manhole construction typically involves setting up traffic control, pavement cutting, trenching, de-watering, installation of ducts and manholes, concrete encasing for the ducts, back filling, grading and compaction, and finally, paving of the trenched area. The ductlines and manholes construction consists of contractors and construction management costs, and are included in the outside services for construction cost category.

The ductlines and manholes construction is currently estimated at approximately \$2,401,000, which is approximately \$940,000 higher than the original cost estimate of \$1,462,000 and accounts for approximately 6% of the total EOTP Phase 1 variance of \$16,168,000. The higher cost is primarily due to the actual costs for the construction of the ductlines and manholes being higher than estimated, as well as the discovery and subsequent remediation of petroleum contaminated soil ("PCS") during construction of one of the ductlines. The \$1,462,000 original cost estimate is broken down as follows: \$889,000 for construction of the ductline and associated manholes; \$259,000 for construction management; \$210,000 for traffic control; and \$104,000 for riser pole installations. The \$889,000 for the construction of the ductlines and associated manholes assumed 2,560 feet of ductline. This averaged to approximately \$347 per feet of installed ductline and associated manholes.

In 2008, six pre-qualified contractors were invited to competitively bid on this work. Three of the contractors declined to bid citing commitments to other projects. The remaining three contractors' respective bids ranged from \$1,428,000 to \$4,649,000. After a comprehensive evaluation, Paul's Electric, the contractor with the \$1,428,000 bid, was awarded the contract. The successful contractor's per unit cost averaged \$558 per feet, which is approximately 61% more than originally estimated. In total, the cost to construct the ductlines is approximately \$539,000 higher than originally estimated.

In 2008, PCS was discovered during trenching on Makaloa Street for the Makaloa-McCully 46kV lines. In accordance with various Federal and State of Hawaii environmental and hazardous materials laws, construction work must stop upon discovery of a potential environmental hazard. After identification and determination of the quantities of the substances discovered, an appropriate remediation plan must be developed before work can resume.

In this case, the remediation plan required that the PCS be removed, treated and finally disposed of at a certified facility as required by applicable laws. It is estimated that the PCS discovery will cost approximately \$130,000, including contractor stand-by time as the remediation plan was developed and approved, and the costs to implement the remediation plan.

While the ductline construction is complete, a change request for some additional work (estimated at \$41,000) plus the PCS related costs is being processed. Thus, the total estimated cost for the ductline construction under Paul's Electric is estimated at \$1,599,000.

In addition, there were other factors that increased the ductlines and manholes construction cost. For example, there was an increase in construction management cost of $65,000, due to the construction of the ductlines and manholes taking longer than anticipated. In addition, some miscellaneous ductline work (i.e., $164,000) was required near Makaloa and McCully Substations that was not included in the Paul's Electric contract.

12kV and 46kV Cable Installations. Cable installations typically involve setting up traffic control, de-watering of manholes, setting up cable reels and pulling equipment, removing existing cables, installing pull lines in the ducts between manholes, pulling new cables into a manhole and through a duct to another manhole, racking the cable in the manholes, and finally, splicing cables ends together in the manholes.

The Company construction labor for the cable installations is currently estimated at approximately $545,000, which is approximately $351,000 higher than the original cost estimate of $194,000. The current labor hours forecasted are 12,612 hours versus the initial estimate of 4,961 hours. The current average hourly labor rate for the Company personnel is approximately $43 per hour versus the initial hourly rate estimate of $39 per hour. The increase is primarily due to more construction labor hours being required than originally estimated, and to a lesser degree, an increase in the average hourly rate for the Company labor.

The labor effort to install the 12kV and 46kV cables was significantly underestimated in 2003. The initial estimate assumed minimal disruptions or problems during the installations. However, in actuality, the installation of the Makaloa-McCully 46kV lines encountered four significant challenges that created inefficiencies for the electrical crews.

First, nearly all the manholes contained large amounts of water and dirt which needed to be removed before the cable work could commence. This created inefficiencies as the crews had to wait for the manholes to be pumped out and cleaned before they could enter the manholes and install the cables. These manholes are located in an area that was affected by severe flooding during the torrential rains and the overflow of Makiki Stream in March through April 2006, which is the likely cause of the large amount of dirt that was encountered.

Second, an irate owner of an automotive business near the work area claimed that the cable installation work was negatively impacting his business. To accommodate the owner, the work near this business was re-scheduled to be done only on Sunday mornings, which increased the amount of time and effort to install the cables in that particular area.

Third, it was decided that work on Makaloa Street and Kalakaua Avenue would need to be done on the weekends in the morning hours to minimize traffic impacts to the various businesses in this area.

And fourth, existing cables could not be removed in a certain section of ductline to make room for the new 46kV cables. After two days of trying to remove the cable, a contractor was hired to excavate and expose the ductline so that the cables could be removed. This took another two days until the cables were finally removed and the ductline and roadway repaired and restored. (This problem was cited as a potential risk in HECO ST-8, page 2 in Docket No. 03-0417 in regards to utilizing existing ductlines.)

In addition, for all the 46kV line installations, scheduling the work in an efficient manner was challenging due to the difficulty in securing hold-offs (electrical clearances) for the installation and connection of various circuits. Because there were multiple construction activities occurring at the same time in the same area, hold-offs could not be granted that would allow the work to progress in the most efficient manner. As a result, the work schedules had to be staggered, which required crews to mobilize and demobilize several times for the same circuit installation.

For the 46kV cable installation on Winam Avenue, a design change was made on the location of one of the new riser pole installations to minimize traffic impacts on Mooheau Avenue, the cross street. While traffic impacts were mitigated with the new pole location, the pole installation became more difficult and required additional hours to install the riser pole.

The overheads associated with the Company labor is currently estimated at approximately $1,036,000, which is approximately $438,000 higher than the original cost estimate of $598,000. The increase in overheads cost is directly attributed to the increase in Company labor costs, with a slight offset related to a decrease in Company labor for non-construction of $15,000.

Materials. The subtransmission lines materials cost is currently estimated at approximately $953,000, which is approximately $179,000 higher than the original cost estimate of $774,000 and accounts for approximately 1% of the total EOTP Phase 1 variance of $16,168,000. The major contributor to the subtransmission lines materials costs was the higher than estimated cost of the new underground 46kV cables.

Of the $774,000 originally estimated for materials, approximately $383,000 was assumed for the 46kV cables. This averaged to approximately $45 per circuit feet[4] of 46kV cable. The actual cost of the 46kV cables that were ordered in 2009 and installed in 2010 totaled approximately $521,000. This averaged to approximately $61 per circuit feet, which is approximately 36% more than originally estimated. In total, the 46kV cables cost was approximately $138,000 higher than originally estimated. (It is noted that the 46kV cables used for this project are the same type of cables that were used in the Ko Olina Substation project (Docket No. 05-0056) and cited as one of the factors for that project's higher actual costs as discussed in HECO ST-17D, pages 17 through 21, of Docket No. 2008-0083.)

In addition to the 46kV cables, the actual costs for nearly all the other materials such as 46kV splices and terminators were higher than originally estimated.

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[4] Circuit feet represents physical distance and does not represent the actual linear distance of cable required for an installation. For example, if the physical or circuit distance between terminal points were 500 feet, then the total amount of cable that would be required would include the 500 feet plus an additional 200 feet to allow for vertical variations in the ductline, cutting of the cable ends, and racking the cable in manholes.

AFUDC. The AFUDC for the subtransmission lines component is currently estimated at approximately $348,000, which is approximately $158,000 higher than the original cost estimate of $191,000. The increase is due to primarily to the increase in costs for the subtransmission lines overall, and to a lesser degree, the delay in service date from 2007 to 2010.

Permitting & Approval Costs Component

The Permitting and Approval Costs component is currently estimated at approximately $2,768,000, which is approximately $1,277,000 or 86% higher than the original cost estimate of $1,491,000. The $1,277,000 accounts for approximately 8% of the total EOTP Phase 1 variance of $16,168,000. The Permitting and Approval Costs component covers the activities to support the Docket No. 03-0417 regulatory proceeding and the environmental assessment process. This also includes activities that took place after the denial of the land permit application by the State Board of Land and Natural Resources ("BLNR") in 2002.

The reason for the cost increase to the Permitting and Approval component is related to the length of the proceeding for Docket No. 03-0417, and the work required to complete the environmental assessment process and the approval proceeding. The proceeding for Docket No. 03-0417 was initially estimated to take approximately 22 months to complete. However, the proceeding took 3 years and 10 months or approximately two years longer than originally estimated. The major cost contributors to the Permitting and Approval Costs component include AFUDC and the consultant services.

AFUDC. The AFUDC for the Permitting and Approval Costs component is currently estimated at approximately $980,000, which is approximately $661,000 higher than the original cost estimate of $319,000. This increase in AFUDC is related to both the increase in direct costs for this component and the delay in the project.

Consultant Services. The consultant services categorized under outside services costs for the Permitting and Approval component is currently estimated at approximately $1,237,000, which is approximately $472,000 higher than the original cost estimate of $765,000. These costs start from October 2003, when the Company selected the Kamoku 46kV Underground Alternative Expanded (EOTP Phases 1 and 2) as the preferred alternative to request Commission approval.

The consultant services utilized to support the proceeding and the environmental assessment process included legal counsel, environmental reporting, engineering studies, and construction management guidance. In addition, the various expert witnesses that participated in the proceeding on topics such as transmission planning, live-working maintenance, electric and magnetic fields ("EMF"), and health issues were also included as part of the consultant services.

In addition, there were other contributors that increased Permitting and Approval costs from the initial estimate. For example, the other contributors that increased the Permitting and Approval costs are the Company's labor and associated overheads. The Company labor is currently estimated at approximately $268,000, which is approximately $38,000 higher than the original cost estimate of $230,000. The activities associated with the Company labor included engineering and project management coordination, review of the various consultant work products, and participation as witnesses in the proceeding. As mentioned previously, the increase is due to the docket proceeding taking longer than anticipated. The associated overheads are currently estimated at approximately $282,000, which is approximately $105,000 higher than the original cost estimate of $177,000. The increase in overheads cost is directly attributed to the increase in Company labor costs.

Distribution Substations Costs Component

The distribution substations are currently estimated at approximately $3,367,000, which is approximately $1,363,000 or 68% higher than the original cost estimate of $2,004,000. The $1,363,000 variance accounts for approximately 8% of the total EOTP Phase 1 variance of $16,168,000. The major contributor to the higher distribution substations costs is the materials.

Materials. The distribution substation materials cost is currently estimated at approximately $1,342,000, which is approximately $566,000 higher than the original cost estimate of $776,000. The $566,000 variance accounts for approximately 4% of the total EOTP Phase 1 variance of $16,168,000.

The primary reasons for the higher costs for the distribution substation materials are the costs for the 46kV-12kV, 12.5MVA transformer ("12.5MVA transformer") and 15kV switchgear for the Makaloa Substation, where the actual prices came in higher than estimated. Of the $776,000 originally estimated for all materials associated with various distribution substations for EOTP Phase 1, approximately $272,000 was initially assumed for the transformer and $139,000 for the switchgear. Through established manufacturer alliances in place in 2008, the transformer was procured at a cost of $470,000 and the switchgear at a cost of $212,000, which were $200,000 and $73,000, respectively, more than originally estimated.

Other Cost Contributors. The other contributors that increased the distribution substations costs are the equipment installations, outside consultants, and AFUDC.

The equipment installations involve constructing underground ductlines for relay and control wiring, installing junction boxes, replacing switches, replacing bus conductors, installing the 12.5MVA transformer and 15kV switchgear, installing motor operators, installing relay and control wiring, and testing. The equipment installations performed by Company construction labor is currently estimated at approximately $450,000, which is approximately $190,000 higher than the original cost estimate of $261,000. The current labor hours forecasted are 10,754 hours versus the initial estimate of 7,370 hours. The current average hourly labor rate for the Company personnel is approximately $42 per hour versus the initial estimated hourly rate of $35 per hour. The increase is primarily due to more construction labor hours required than originally estimated, and to a lesser degree, an increase in the average hourly rate for the Company labor.

As the electrical crews started the construction at the various distribution substations, it was determined that more work was required than initially estimated. For example, after closer inspection, it was determined that more 46kV switches needed to be replaced than initially anticipated due to their deteriorated conditions. Or, it was discovered that the electrical ratings of the existing 46kV switches were not compatible with the bus that was originally planned to be replaced as part of the project. Another example is that more control conduits and wiring were required than originally estimated at certain substations. Only after crews started the actual installation and opened up existing junction boxes was it determined that the existing wiring was inadequate to properly upgrade the auto-transfer scheme as required by the project. Overall, scheduling the work in an efficient manner was challenging due to the difficulty in securing hold-offs (electrical clearances) for the work in the substations. Because there were multiple construction activities occurring at the same time in the same area, hold-offs could not be granted that would allow the work to progress in the most efficient manner. As a result, the work schedules were extended longer than anticipated.

The overheads are currently estimated at approximately $885,000, which is approximately $303,000 higher than the original cost estimate of $582,000. The increase in overheads cost is directly attributed to the increase in Company labor costs with a slight offset related to a decrease in Company non-construction labor of $41,000.

The cost for the outside consultants is currently estimated at approximately $255,000, which is approximately $254,000 more than the initial cost estimate of less than $1,000 for drawing reproduction. It was initially assumed that the detailed design work would be performed by Company labor. However, due to high work demand, the Company decided to consult this work out, which increased the outside consultant costs but decreased Company non-construction labor by $41,000, as mentioned previously.

AFUDC. The AFUDC is currently estimated at approximately $212,000, which is approximately $95,000 higher than the original cost estimate of $117,000. The increase is due to primarily to the increase in costs for the distribution substations overall, and to a lesser degree, the delay in service date from 2007 to 2010.

Cost Increase Due to Overall Delay in Project

As described earlier, EOTP Phase 1 was estimated for completion in mid-2007 and EOTP Phase 2 in early 2009. This assumed that the proceeding for Docket No. 03-0417 would be completed (i.e., final decision issued) in the 3rd or 4th quarter of 2005. Instead, the proceeding was completed in October 2007, which required a new schedule to be developed. Based on the new schedule, the estimated service date for EOTP Phase 1 was June 2010, which is approximately three years later than initially estimated in Docket No. 03-0417.

The major cost contributor related to the overall delay in EOTP Phase 1 is the AFUDC. The total AFUDC for EOTP Phase 1 is currently estimated at approximately $23,117,000, which is approximately $8,156,000 or 55% higher than the original cost estimate of $14,960,000. The $8,156,000 variance accounts for approximately 50% of the total EOTP Phase 1 variance of $16,168,000.

The major cost contributor to the total estimated AFUDC is the AFUDC associated with the Pre-2003 Planning and Permitting Costs ("Pre-2003 Costs"). The treatment of these costs and the associated activities are discussed in Exhibit E.

The direct Pre-2003 Costs incurred is approximately $12,836,000. (This is the "Planning Costs" component, as shown in Exhibit B, page 2.) The estimated AFUDC based on an EOTP Phase 1 service date of June 2010 is approximately $20,370,000, which is approximately $6,810,000 or 50% higher than the original estimate of $13,560,000. The $6,810,000 variance represents approximately 42% of the $16,168,000 total cost variance for EOTP Phase 1.

The increase in AFUDC is attributed to the delay in the service date of EOTP Phase 1 from mid-2007 to mid-2010. For example, the average yearly AFUDC cost for the Pre-2003 Costs during the delay period of 2007 to 2010 was approximately $2.3 million per year.

In addition, the other cost contributors to the total estimated AFUDC of EOTP Phase 1 are the AFUDC associated with the Permitting and Approval, subtransmission lines, transmission substation, and distribution substations. As mentioned earlier in this exhibit, the increased AFUDC is due primarily to the increased costs for these components overall, and to a lesser degree, the delay in service date from 2007 to 2010.

In addition to AFUDC, there would have been other reductions in cost if the EOTP Phase 1 in-service date was earlier than 2010. As mentioned earlier, some of the increased Company labor, material and construction costs were related to the project being delayed.

ENERGY DELIVERY

CONTRACT GUIDELINES

August 18, 2003

Approved by:

Stephen K. Yoshida
Manager of Engineering

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Manager of Support Services

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Vice President of Energy Delivery

August 18, 2003

ENERGY DELIVERY CONTRACT GUIDELINES

Hawaiian Electric Company is committed to the highest standards of business conduct in our relationships with our contractors, consultants, and suppliers as per our Corporate Code of Conduct dated February 1, 2003. Consequently, the attached contract guidelines were established for the Energy Delivery process area.

1. Material Purchase Contract Guidelines
2. Construction & Services Contract Guidelines
3. Engineering Consulting Contract Guidelines

Parceling of contracts to avoid bidding is not allowed.

MATERIAL PURCHASE CONTRACT GUIDELINES

Hawaiian Electric Company is committed to the highest standards of business conduct in our relationships with our contractors, consultants, and suppliers as per our Corporate Code of Conduct dated February 1, 2003. Consequently, the following material purchase contract guidelines have been established for the Energy Delivery process area.

Bid Contracts

As a rule, material purchases shall be issued for bid unless a sole source purchase can be justified.

Consideration shall be given to using the Reverse Auction process for all bid contracts.

Non-bid Contracts

Non-bid purchases are allowed in select cases. The following reasons are acceptable justifications for waiving competitive bids:

1. Inadequate qualified competition, i.e., sole source.
2. Inadequate purchase specifications.
3. Insufficient time for solicitation and evaluation of bids, i.e., an emergency.
4. The requirements are too vague to establish a specification suitable for bidding.
5. The dollar value is too low to justify bidding.

If an initiating department specifies a sole source, it is the initiator's responsibility to provide the justification for waiving bids. Administration of this guideline is the responsibility of the Purchasing Division.

All orders without competitive bids above a value of $10,000 shall be justified in a memo signed by the approver of the contract based on the initiating department's "Delegation of Authority" levels for approval by the Director of Purchasing or the Manager of Support Services.

Material Alliances

Material alliances are a business arrangement between suppliers and buyers. These alliances or partnerships with certain equipment manufacturers originated through bid contracts based on favorable past experience with respect to price and service. An alliance was formed to increase the potential for improvement to both areas. HECO would gain preferential treatment on the priority of its orders and even receive advice on *specifying the equipment to lower cost.*

Either party can terminate the alliance at any time. In addition, the alliance is evaluated annually to determine if it should continue based on the realization of any anticipated benefits.

August 18, 2003

CONSTRUCTION & SERVICES CONTRACT GUIDELINES

Hawaiian Electric Company is committed to the highest standards of business conduct in our relationships with our contractors, consultants, and suppliers as per our Corporate Code of Conduct dated February 1, 2003. Consequently, the following construction contract guidelines have been established for the Energy Delivery process area.

Bid Contracts

As a rule, construction projects and services shall be issued for bid unless a sole source contract can be justified. The minimum threshold to consider going out for bid is presently at $10,001 based on an Internal Audit Report on "Contract Rates" (Audit No. OP2001-1 dated September 19, 2002). This value was set to avoid the expense of preparing bids for small projects where this effort is not cost effective for HECO or the service provider.

Non-bid Contracts

Non-bid or negotiated contracts, greater than $10,000, are allowed in select cases. The following reasons are acceptable justifications for waiving competitive bids:

1. Inadequate qualified competition, i.e., sole source.
2. Insufficient time for solicitation and evaluation of bids, i.e., an emergency.
3. The requirements are too vague to establish a specification suitable for bidding.
4. On-site contractor available when cost effective and expedient.

If an initiating department specifies a sole source, it is the initiator's responsibility to provide the justification for waiving bids. Administration of this guideline is the responsibility of the Contract Administrator.

All construction and services contracts without competitive bids above a value of $10,000 shall be justified in a memo signed by the approver of the contract based on the initiating department's "Delegation of Authority" levels.

August 18, 2003

ENGINEERING CONSULTING CONTRACT GUIDELINES

Hawaiian Electric Company (HECO) is committed to the highest standards of business conduct in our relationships with our contractors, consultants, and suppliers as per our Corporate Code of Conduct dated February 1, 2003. Consequently, the following engineering consulting contract guidelines have been established.

The Energy Delivery process area of Hawaiian Electric Company normally utilizes non-bid contracts to acquire engineering consulting services. These non-bid contracts are based on the "Qualifications Based Selection" process. Generally, this process specifies consulting contracts to be negotiated with a qualified consultant for the work.

For some projects, more than one firm may be asked to provide a statement of qualifications. However, after the most qualified consultant is identified, contracts are generally negotiated and bids are rarely solicited. Commonly, the situation does not favor solicitation of competitive bids for the following reasons:

1. It is rare that the selection process identifies at least two equally qualified consultants.
2. Use of a less qualified consultant can often greatly increase the cost of construction, far beyond the total consultant fee.
3. Generally at the start of negotiations, the work scope is not well defined. As a result, the consultants are expected to represent the Owner's interests and a different relationship exists as compared to a normal buyer-seller relationship.

<u>Qualifications of Engineering Consultants</u>

Engineering consultants are evaluated in the following areas:

1. Experience with HECO and other projects.
2. References and industry reputation.
3. Responsiveness and accuracy.
4. Technical expertise of personnel.
5. Sensitivity to HECO's needs.
6. Value provided and classification of hourly rates.

Non-bid contracts that **exceed $100,000** must be documented in a memo signed by the approver of the contract based on the initiating Department's "Delegation of Authority" levels. The documentation should include, if applicable:

1. A statement that the requester has thoroughly researched the service to be provided.
2. A detailed explanation of the particular service need.
3. A list of the other consultants/contractors considered.

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4. An explanation of why the consultant/contractor was selected over other consultant/contractors including a detailed comparison of features.
5. Documentation of what the requester has done by way of cost comparison to determine that the charge is not out of line with the current market pricing for the service.

The main purpose is to document why we did not bid out the contract. If the reason is because the consultants are the only people that can do the work (or some other simple reason), then a sentence or two stating that would be sufficient. However, if there are several consultants that could have done the work, then the decision process needs to be documented as to why we did not use the competitive bid process.

Documentation should be kept in:

1. The project files.
2. The contract files.
3. The Legal Department (original contract)

The following reasons are acceptable justifications for proceeding with non-bid contracts:

1. Most qualified engineering consultant desired – The provider of the engineering consulting services is the leader in their field with unique capabilities that are not known to be available from another source at a reasonable price.
2. Insufficient time for solicitation and evaluation of bids, i.e., an emergency.
3. The requirements are too vague to establish a specification suitable for bidding. In this situation, the consultant is depended upon to work with the Company's interest in mind by determining what is required to solve the problem.
4. **Highly sensitive/confidential work.**

If there are two or three engineering consultants of equivalent qualifications that can do the work, consideration should be given to rotating the work among the consultants when possible. (Also, see section on Master Services Agreements below.)

<u>Master Services Agreements</u>

Master Services agreements are utilized to streamline the process to obtain engineering services by negotiating contract terms and conditions prior to issuing work. In general, these agreements are intended for smaller projects/studies that are recurring in nature. The engineering consultants are selected based on their qualifications and may have performed work for HECO through the competitive bid process. Satisfactory past performance and competitive pricing by these engineering consultants are heavily considered in justifying entering Master Services agreements with them.

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When possible, Master Services agreements should be initiated with two or three engineering consultants of equivalent qualifications to ensure availability of services. It also gives HECO the opportunity to compare the level of service and quality of work between the sources on a periodic basis. Work assignments should be rotated among the consultants. This provides for consultants that are familiar with our electrical system configuration, personnel, standards, and work procedures. Consequently, they are able to respond more quickly with less checking on our part and rework on their part. Communication is also apt to be clearer and less time consuming.

When HECO needs to have work done under a master agreement, a scope of work and cost estimate shall be developed. The consultant shall be provided with this scope and asked to provide a proposal to complete the work to include an estimate of the cost to do the work. The engineer or designer initiating the work must agree that the consultant's proposal is appropriate and the cost consistent with the estimate. The engineer shall then prepare a Work Authorization for approval. Work Authorizations shall be approved at the appropriate level in accordance with the established Delegation of Authority contract limits.

The Master Services Agreements have a pre-established term of up to three or four years. At the completion of each work authorization, the consultant shall be evaluated on responsiveness, technical expertise, sensitivity to HECO's needs, and value provided to determine if the Master Services Agreement should continue to be utilized or renewed at the end of Master Services Agreement's term.

Bid Contracts

Engineering consulting contracts may occasionally be bid if the project is of significant enough value where there are qualified consultants willing to risk the time and expense of bidding on the project. For example, consultants from outside Hawaii must decide whether the value of the project is worth the risk of not winning the bid while incurring significant labor, travel, and lodging cost to develop and present their proposal to HECO's engineers and Management with a two to three person team over the course of two to three days including travel time.

PRE-2003 PLANNING COSTS AND AFUDC

Pursuant to the Stipulation filed on October 28, 2005 in Docket No. 03-0417, Hawaiian Electric and the Consumer Advocate agreed that any issue as to whether the "Pre-2003 Planning and Permitting Costs" and the related AFUDC should be included in the costs of the EOTP should be reserved to and may be raised in the next general rate increase proceeding (or other proceeding) in which Hawaiian Electric seeks approval to recover the EOTP costs. On November 4, 2005, pursuant to Order No. 22104, the Commission approved, in part, the Stipulation. In addition, the Commission agreed that the detailed examination of the Pre-2003 Planning and Permitting Costs and the identification of those costs for possible inclusion in rate base would more appropriately be completed in a rate increase proceeding, rather than in an application for approval to commit funds for a capital expenditure. These costs include the planning and permitting costs incurred by Hawaiian Electric to address several transmission problems in the eastern half of Oahu. Prior to 2003, the preferred alternative to address the transmission problems was the partial underground/partial overhead (using Waahila Ridge) 138kV line for which Hawaiian Electric requested a Conservation District Use Permit ("CDUP") from the Board of Land and Natural Resources ("BLNR").

The Pre-2003 Planning and Permitting Costs were $12,836,000, and based on an assumed service date of 2007, Hawaiian Electric estimated the associated AFUDC to be $13,560,000 for a total of $26,396,000.

Based on a June 2010 service date for EOTP Phase 1, the actual associated AFUDC is $20,370,000, for a total of $33,206,000. (See the "Planning Costs" component in Exhibit B, page 2.)

The planning and permitting costs incurred prior to 2003 are substantial as a result of the extended process required, and Hawaiian Electric's efforts to facilitate public input. For example, in addition to a Community Advisory Committee ("CAC") process, Hawaiian Electric held more than 150 project briefings for public agencies, neighborhood boards, elected officials, and community organizations between 1992 and the publication of the *May 1998 Kamoku-Pukele Transmission Line Project Draft EIS* ("May 1998 Draft EIS"). (See HECO T-19A, filed July 30, 2010, in Docket No. 2010-0080 and HECO T-2, filed December 18, 2003, in this proceeding for additional information.)

A significant portion of the costs expended was attributable to the required Environmental Impact Statement ("EIS") process. The EIS was to provide comprehensive project information to the BLNR and the Commission. Organized project opponents developed a simple and inexpensive mechanism to overburden and delay the EIS process. Over 10,000 individual comments were received on the September 1999 *Kamoku-Pukele 138-kV Transmission Line Project Revised Draft Environmental Impact Statement* ("September 1999 Revised Draft EIS"), that each required an individualized response according to a determination by the Deputy Attorney General. This resulted in the September 2000 Revised Final EIS, an unprecedented document that consisted of 26 volumes and brought out significant concerns with the Hawaii Revised Statutes ("HRS") Chapter 343 process.

Hawaiian Electric's efforts since 1991 have always been directed towards addressing the four East Oahu transmission problems and concerns identified in the initial 1991 transmission planning study, and discussed at length in Docket No. 03-0417. See Docket No. 03-0417: Mr. Pollock's direct testimony, HECO T-3, pages 20-29; Ms. Ishikawa's direct testimony, HECO T-4, pages 1-16; Mr. Pollock's rebuttal testimony, HECO RT-3; and Ms. Ishikawa's rebuttal testimony, HECO RT-4.

In order to address these planning issues, Hawaiian Electric evaluated a substantial number of transmission, sub-transmission and non-transmission options. When the studies identified a 138 kV line linking the Northern Transmission Corridor with the planned southern Transmission Corridor as the preferred technical solution, Hawaiian Electric conducted a routing study and public input process to determine the preferred route. Moreover, as a result of the public input process, Hawaiian Electric continued to evaluate and update its analyses of other options.

The activities that occurred from 1991 to 2002 to address the East Oahu transmission problems are summarized in HECO T-2, pages 11-30, and in HECO RT-2, pages 4-21, in Docket No. 03-0417. The activities included 1) identifying and evaluating the transmission problems and concerns; 2) identifying and evaluating alternatives to address the transmission problems and concerns; 3) identifying permitting requirements; 4) conducting an extensive public scoping and public input process; 5) identifying and evaluating routing alternatives; 6) conducting a HRS Chapter 343 environmental impact statement ("EIS") process; 7) addressing additional factors for a 138kV line due to the passage of Act 95 in the 1997 State Legislature, which amended HRS section 269-27.6; and 8) applying for a Conservation District Use Permit pursuant to HRS Chapter 183C process.

Based on the routing study and continuing public input process, Hawaiian Electric selected a preferred route and commenced the required permitting process for the route. Nonetheless, as a result of the EIS process, a new law enacted to govern the Hawaii PUC's consideration of 138kV lines, and the passage of time, Hawaiian Electric continued to evaluate and analyze other options. The preferred option remained the partial underground/partial overhead (via Waahila Ridge) 138kV line.

When the key permit for the preferred route was denied, Hawaiian Electric again evaluated its options, building on its extensive efforts already undertaken through the earlier studies, public input process, and EIS process.

The project now uses the 46kV system to link the downtown Substations with the Pukele Substation, instead of a 138kV line between the Kamoku and Pukele Substations, in order to address the same transmission system overload situations and transmission substation reliability concerns that were identified in the 1991/1992 studies.

Thus, this project continuity is further indicated by the continued use of the information and studies (e.g., 1995 CH2M HILL Alternatives Study) developed as a result of the earlier planning, permitting and public input process phases of the project.

Before selecting the partial underground/partial overhead 138kV line option (using Waahila Ridge) to address these problems, Hawaiian Electric also considered (1) other options connecting the Kamoku and Pukele Substations with a 138kV line (including all overhead and all underground options), (2) other 138kV line options, and (3) options using the 46kV system, as well as (4) non-transmission options. After the preferred option was no longer available, Hawaiian Electric again considered (1) options connecting the Kamoku and Pukele Substations with an all underground 138kV line, (2) other 138kV line options, and (3) options using the 46kV system, as well as (4) non-transmission options. The Kamoku 46kV Underground Alternative – Expanded option, to be implemented in two independent phases, became the preferred alternative.

Utilities need to plan and incur costs for potential projects, particularly major generation and transmission projects, many years before the need dates for the projects (which dates may change during the course of the projects). This is necessitated by the long lead times required for such things as land use approvals, siting, routing and environmental studies (which may involve time-consuming public input processes), the acquisition of land and land rights, regulatory approvals, the ordering of long lead time materials (which have to be manufactured and shipped to be available when construction starts), and the construction of the projects. Thus, substantial costs may be incurred by necessity a number of years before the need or completion dates for the projects (which may themselves change). Under these circumstances, the related costs should be recoverable from ratepayers.

AFUDC for Pre-2003 Planning and Permitting Costs

As indicated above, the Pre-2003 Planning and Permitting Costs were high because these costs were incurred over the period from 1992 through 2002, and AFUDC was accumulated during this period on the costs as they were incurred, and continued to accumulate until Phase 1 was placed in service in mid-2010.

AFUDC is an accounting procedure for capitalizing the cost of investor-supplied funds used to finance construction projects during the construction period. AFUDC accrual starts once work on a capital project had commenced on a planned progressive basis. AFUDC-related costs encompass costs for planning, designing and permitting construction work. After the initial application, AFUDC is applied every month until the capital project is completed, or until the project is delayed at management's discretion, or is abandoned. In the case of a project delayed at management's discretion, AFUDC is stopped at the point of delay, and is resumed when the project is re-activated. Unlike periods of discretionary delay, it is appropriate to continue applying AFUDC during periods of delay caused by external factors and events beyond management's control.

Hawaiian Electric's transmission planning efforts in the 1991-1992 timeframe identified the East Oahu transmission problems and concerns, and determined that the connection between the Southern transmission corridor and the Pukele Substation was required. Once the capital expenditures project[1] was identified (which was termed the Kamoku-Pukele 138kV Transmission Line project at the time), planning and permitting costs required to implement the project were recorded to construction work in progress ("CWIP"). In Hawaii, CWIP is not included in rate base, and investors only earn a return on their investment in CWIP through the Allowance for Funds used during Construction (AFUDC).

[1] As noted, three separate projects were identified to accomplish this. The separate projects installing lines from Archer Substation to a new Kewalo Substation, and from Kewalo Substation to a new Kamoku Substation, were completed in the 2002-2003 period.